energex™
PETROLEUM INC.

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UIC BRANCH
EPA, REGION 5

United States Environmental Protection Agency
Region 5
77 West Jackson Boulevard
Chicago, IL 60604-3590

Attention: Stephen M. Jann Chief
Underground Injection Control Branch

Reference: WU-16J

Regarding: Additional Information for the Underground Injection Control Permit Application #MI-125-2R-0003, Lanphar 1-12 Injection Well

Dear Sir:

Further to a request to provide additional information with respect to the above injection well please find enclosed a revised application package which addresses inconsistencies and/or deficiencies in:

1. **Attachment Q: Plugging and Abandonment Plan**

   Inconsistency in the plugging schematic and plugging and abandonment plan (Appendix G). A request for a third-party plugging cost estimate is attached in Appendix H.

2. **Attachment O: Plans for Well Failures**

   Updated and revised information as requested.

3. **Attachment R: Necessary Resources**

   In Appendix I is a copy of the Michigan State Blanket Bond and Schedule A of wells included in the State Blanket Bond.

I trust that you will find the following in order and please to do not hesitate in contacting me in writing, by telephone (226-238-0296) or via email at hamiltongeologicalservices@gmail.com .

Yours truly,

Duncan Hamilton, P.Geo.
Chief Operating Officer

Attachment A – Area of Review

Area of review (AOR) shall be a minimum of ¼ mile from the well bore.

The AOR for the proposed injection well is shown in Figure 1.

Figure 1 Map Showing the 1320 ft (1/4 mile) AOR Surrounding the Proposed Injection Well Lanphar 1-12 and Additional Wells Within the AOR

Attachment B – Maps of Wells/Area and Area of Review

1. Include a topographic map which extends one mile beyond the property boundary showing the injection well where fluids from the facility are injected and the project area for which the permit is sought and the AOR.

   A topographic map which extends one mile beyond the property boundary showing the proposed injection well (Lanphar 1-12) is illustrated in Figure 2.

2. In addition the maps for application must include within the AOR: all intake and discharge structures; all hazardous waste treatment, storage, or disposal facilities; the number/name and location of the wells, springs and other surface bodies of water, and drinking water wells listed in public record or otherwise known to the applicant. If any of these features are not present state so.

   There are no: intake and discharge structures; hazardous waste treatment, storage, or disposal facilities, springs and other surface bodies of water, and drinking water wells listed in public record or otherwise known to the applicant. The wells located within the AOR are annotated in Figure 1.

3. A list of all landowners directly in the AOR and their addresses must be submitted.

   A list of the landowners in; and directly adjacent to the AOR are provided below in Table 1. The landowner location maps are referenced to the tax role numbers in Figure's 3 and 4.

Tax Role #	Landowner Name	Address
FOIA Exemption 6, 5 U.S.C § 552(b)(6). 'personnel and medical files and similar files the disclosure of which would constitute a clearly unwarranted invasion of personal privacy.' [redacted]		

Table 1 List of Landowners and Addresses within the AOR

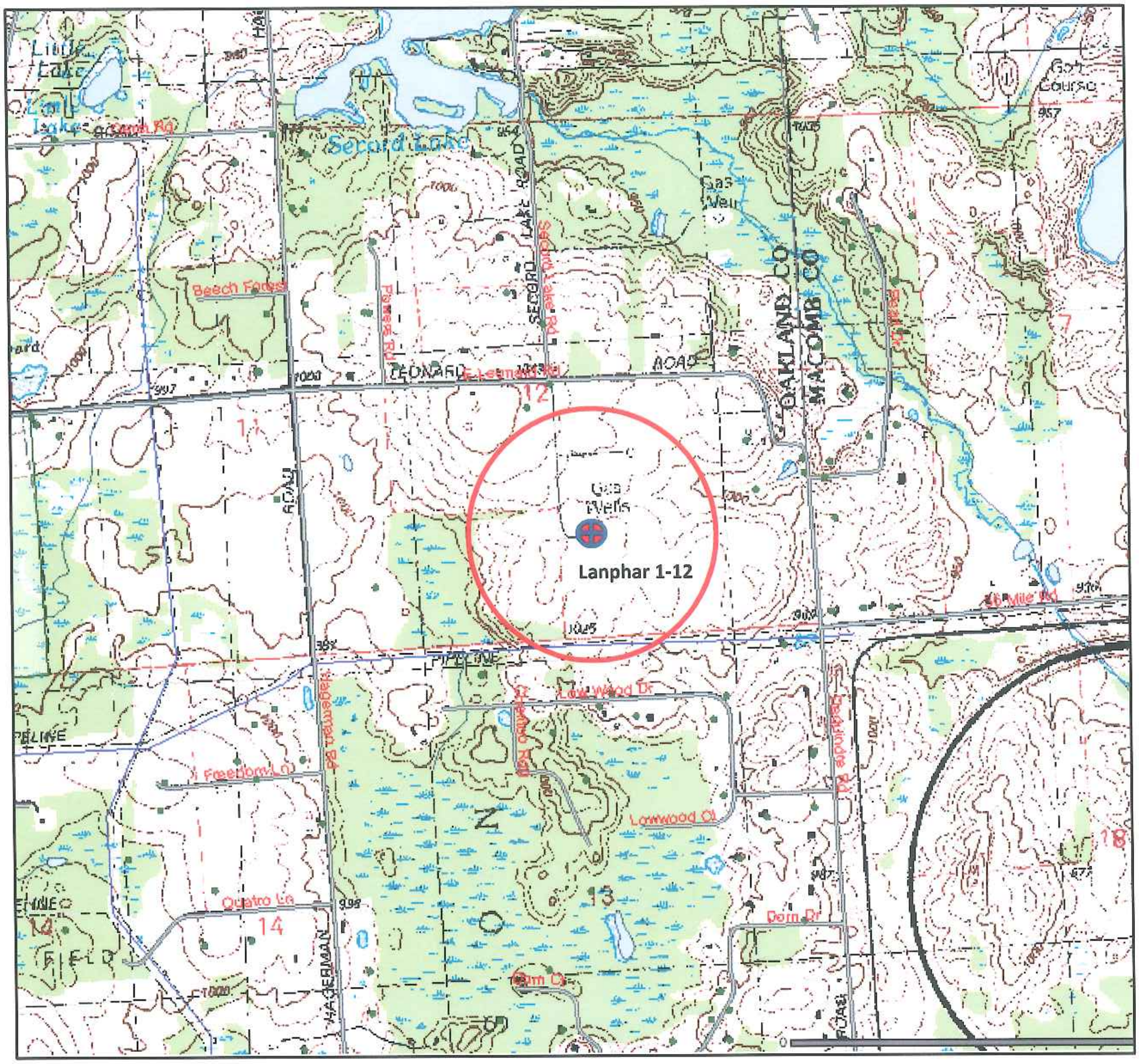
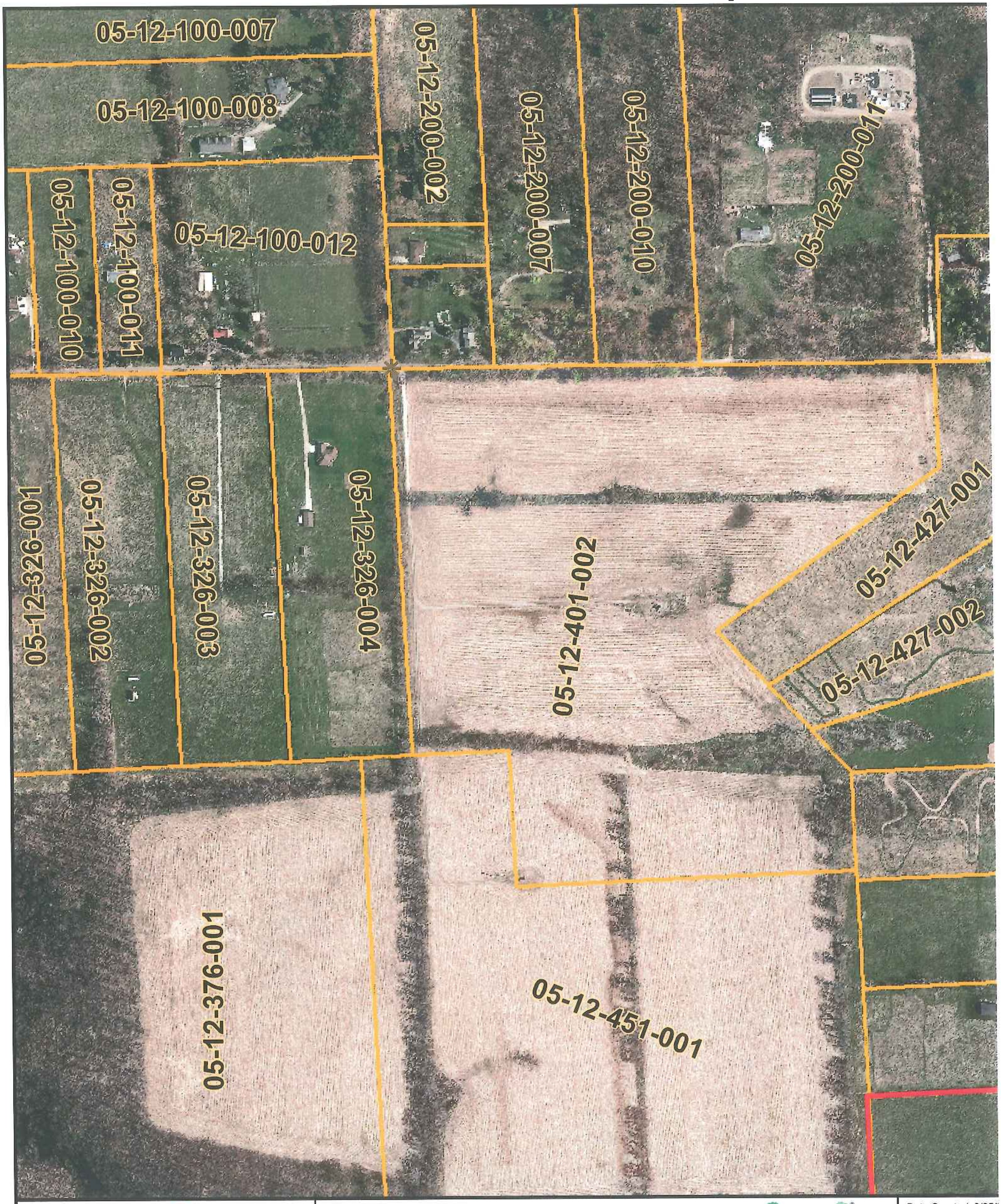


Figure 2 Topographic Map Showing Lands Within One Mile of the Proposed Injection Well Location - Lanphar 1-12 and the AOR.

Figure 3

North AOR Residence Map



2 Foot Contours
5 Foot Contours
FEMA Base Flood Elevations
FEMA Cross Sections
100 yr - FEMA Floodplain
100 yr (detailed) - FEMA Floodplain
500 yr - FEMA Floodplain
FLOODWAY - FEMA Floodplain

Disclaimer: The information provided herewith has been compiled from recorded deeds, plats, tax maps, surveys and other public records. It is not a legally recorded map or survey and is not intended to be used as one. Users should consult the information sources mentioned above when questions arise. FEMA Flooplain data may not always be present on the map.

OAKLAND COUNTY MICHIGAN
Economic Development & Community Affairs
L. Brooks Patterson
Oakland County Executive

Date Created: 2/25/
NORTH
1 inch = 400 feet

Oakland County One Stop Shop 2100 Pontiac Lake Road Bldg. 41 West Waterford, MI 48328 Phone: 248-858-0721 Web: www.advantageoakland

Figure 4

South AOR Residence Map

2 Foot Contours
5 Foot Contours
FEMA Base Flood Elevations
FEMA Cross Sections
100 yr - FEMA Floodplain
100 yr (detailed) - FEMA Floodplain
500 yr - FEMA Floodplain
FLOODWAY - FEMA Floodplain

Disclaimer: The information provided herewith has been compiled from recorded deeds, plats, tax maps, surveys and other public records. It is not a legally recorded map or survey and is not intended to be used as one. Users should consult the information sources mentioned above when questions arise. FEMA Flooplain data may not always be present on the map.

OAKLAND COUNTY MICHIGAN
Economic Development & Community Affairs
L. Brooks Patterson
Oakland County Executive

Date Created: 2/25/2

NORTH
1 inch = 400 feet

4. The number or name and location of all existing producing wells, injection wells, abandoned wells, dry holes and water wells and mines (surface and subsurface) quarries and other pertinent surface features including residences and roads and faults which are known or suspected.

   There are no water wells, mines (surface and subsurface) quarries or known faults within the boundaries of the AOR. Three wells are located within the AOR of which; Lanphar 1-12 is the proposed gas injection well. Table 2 below summarizes the required information for the three wells that are shown in Figure 1.

Well Name	Location
Lanphar 2-12	NW1/4 NW1/4 SE1/4 Sec12 T5N R11E, Addison Twp., Oakland County
Lanphar 7-12	NW1/4 SE1/4 NE1/4 Sec12 T5N R11E, Addison Twp., Oakland County
Lanphar 1-12	NW1/4 SW1/4 SE1/4 Sec12 T5N R11E, Addison Twp., Oakland County

Table 2 Wells located within the AOR

Attachment C – Corrective Action Plan and Well Data

1. Tabulation of data on all wells within the AOR. Include a description of each well's type, construction, date drilled, location, depth, record of plugging and/or completion and any additional information.

2. The wells in Table 3 are located within the AOR and a description of each well's type, construction, date drilled, location, depth, record of plugging and/or completion and any additional information is included in Appendix A.

Well Name	Type	Date Drilled	Location	Depth	Record of Completion
Lanphar 2-12	Capped	March 16, 1979	NW1/4 NW1/4 SE1/4 Sec12 T5N R11E	4425'	Appendix A
Lanphar 7-12	Oil Producer	Nov. 19, 1985	NW1/4 SE1/4 NE1/4 Sec12 T5N R11E	4390'	Appendix A
Lanphar 1-12	Suspended	Feb. 23, 1978	NW1/4 SW1/4 SE1/4 Sec12 T5N R11E	4339'	Appendix A

Table 3 Well Information for wells within the AOR

3. The proposed Class II injection well (Lanphar 1-12) will not be operated over the fracture pressure of the injection formation. The proposed injection well is to operate at a maximum injection pressure of 1400 psig.

   The calculated fracture pressure of the Lanphar 1-12 wells is 3,374 psig at the mid-point of the perforated interval (injection zone) at 4218'KB (0.8 X4218) less the pressure exerted by a column of natural gas in the well.

P1 = $\dfrac{Ps}{\text{Exponent } GL/53.34 \times T}$ P1 = $\dfrac{Ps}{1 - e^{GL/53.34\,T - 1}}$

P1 = Pressure at the wellhead
Ps = Pressure at bottom of well
Ps – P1 = Pressure due to weight of static gas column
L = Average length of gas column
G = Specific gravity of gas
e = Naperian logarithm base = 2.71828
T = Average temperature

4. The wells located within the AOR are interpreted to be properly sealed and completed.

Attachment D – Maps and Cross-Sections of USDW'S

Not applicable to Class II wells.

Attachment E – Name and Depth of USDWs

Include the geological name and depth of bottom of all USDWs in the AOR. USDWs include all aquifers with water quality less than 10,000 milligrams per liter of total dissolved solids (TDS) and capable of yielding 2 gallons per minute of water. These aquifers need not presently supply drinking water to be considered a USDW. Additionally, any zone supplying drinking water regardless of quality is a USDW. The depths of the USDWs are to be determined if possible from the evaluation of the borehole electric logs. The water resistivity of the deepest USDW is to be calculated by the static spontaneous potential method and converted to TDS or sodium chloride equivalent to verify that the zone in question has less than 10,000 mg/l TDS.

The Coldwater Shale subcrops under the lands encompassed by the AOR and according to the U.S. Geological Survey Report 94-4242, the Coldwater Shale is not considered a USDW. The overburden quaternary sediments overlying the Coldwater Shale are potentially a USDW.

For existing wells or proposed well conversions: The permit application for any existing well or any well convened after the effective date of the program must provide an electric log through the entire borehole. The logs must be evaluated by a knowledgeable log analyst. All formations should be identified on the logs or a separate listing provided with names and depths to bottom.

See attached Compensated Neutron-Formation Density log in Appendix B from the surface to total depth of the well. Formation tops are annotated on the log and are also tabulated in Table 4.

FORMATION NAME	DEPTH TOP OF FORMATION (FEET KB)
Base of Drift and top of Coldwater Shale	362
Sunbury	1026
Berea	1084
Bedford	1154
Antrim Formation	1366
Antrim Shale	1508
Dundee	1826
Sylvania	2326
Bois Blanc	2410
Bass Island	2502
Salina G Unit	2701
Salina F Unit	2752
Salina F Salt	2823
Salina E Carbonate	3220
Salina D Salt	3316
Salina C Shale	3348
Salina B Salt	3416
Salina A-2 Carbonate	3348
Salina A-2 Evaporate	3934
Salina A-1 Carbonate	3959
Niagaran Guelph (Brown)	3988
Niagaran Lockport (Grey)	4335

Table 4 Formation Tops in Lanphar 1-12

Attachment F – Maps and Cross Sections of Geological Structure of Area

This application requirement does not apply to Class II.

Attachment G – Geologic Data on the Injection and Confining Zones

1. For all injection and confining zones, provide: the geologic name, a lithological description, the thickness and the depth to bottom or top of each unit.

   Injection Zone

   The proposed injection zone for the Lanphar 1-12 is the Niagaran Guelph formation (Figure 5). Lithologically, the Niagaran Guelph formation is a porous and permeable, fine to medium crystalline dolomite with varying degrees of salt-plugging. Petrographically, from core analyses obtained from the Lanphar 1-12 (Appendix C), porosity varies generally between 3 and 12 % and permeability ranges from 0.1 to 5.0 millidarcies. The Niagaran Guelph formation in the Lanphar 1-12 well was penetrated at a depth of 3988' and the base of the unit was at 4334' for a total thickness of 346'.

Confining Zones

The Niagaran Guelph formation is confined below by the Niagaran Lockport formation and above by an alternating carbonate, shale and evaporate sequence which is termed the Salina Group (Figure 5). The main confining zones in the Salina consist of the A-2 Carbonate, A-2 Evaporate, Ruff (A-1 Carbonate, A-1 Evaporate and the Cain Formation (A-0 Carbonate). The A-1 Evaporate and Cain formation are absent in the Lanphar 1-12.

A-2 Carbonate

The A-2 Carbonate was penetrated at 3762' and its thickness is approximately 172 feet. Lithologically, the formation is a medium brown to dark brown, very finely crystalline to cryptocrystalline dolomite and dense with no visible porosity or permeability.

A-2 Evaporate

The A-2 Evaporate was encountered at a depth of 3934' and has a thickness of approximately 25 feet. Lithologically the unit is white to cream coloured anhydrite with no porosity or permeability.

Ruff (A-1 Carbonate)

The A-1 Carbonate was penetrated at 3959' and is approximately 29 feet. The formation lithologically is a light to medium grey to grey-brown, very finely crystalline to microcrystalline dolomite with scattered salt-filled sucrosic texture.

The injection zone is underlain by the:

Niagaran Lockport (Grey)

The Niagaran Lockport top was picked using samples at a depth of 4335' and total depth was attained at 4339 ' indicating a penetrated thickness of 5 feet. Lithologically, the formation is a dark grey, argillaceous and dense dolomite.

2. All logs submitted should show names and depths of formation tops. The confining zone(s) should be identified on a log that identifies "confining characteristics". An electric log through both the confining and injection zones should also be submitted. An interpretation by a knowledgeable log analyst of the nature of the confining zones, including lithology must be provided.

   A compensated neutron-formation density log with annotated formation names and tops is attached in Appendix B. The injection interval and existing perforations are also annotated on the attached log.

3. For existing Class II wells or conversions, information on the injection and confining zones should be provided from existing information, preferable from borehole logs in addition to other information.

Petrographic information on the injection and confining zones which are described above was obtained from the compensated neutron-formation density log (Appendix B), core analysis (Appendix C) and rock sample descriptions (Appendix D).

Period	Epoch	N. American Age	N. American Stage	Michigan Subsurface Group	Michigan Subsurface Formation	Michigan Informal Literature	Wisconsin	Indiana	Illinois	Ohio
Devonian										
Silurian	Late	Pridoli (419-416)	Cayugan	Bass Islands	undiff				Racine	
					G	G	Racine Fm	Wabash Fm (Mississinewa and Liston Creek)		
		Ludlow (423-419)		Salina	F	F				
					E	E				
					D	D				
					C	C				
					B	B				
					A-2 Carb	A-2 Carb				
					A-2 Evap	A-2 Evap				
					Ruff	A-1 Carb				
					A-1 Evap	A-1 Evap				
					Cain	A-0 Carb		Louisville and Waldron		
	Middle	Wenlock (428-423)	Niagaran	Niagara	Guelph Dol.	Brown Niagaran			Waukesha	
					Lockport Dol.	Gray Niagaran				
						White Niagaran				
				Manistique	undiff	Manistique				
				Burnt Bluff	undiff	Clinton		Salamonie	Joliet	Brassfield Fm
	Early	Llandovery (444-428)	Alexandrian	Cataract	Cabot Head Sh.					
					Manitoulin Dol.					
Ordovician										

Figure 5 Stratigraphic Nomenclature for Silurian strata in Michigan and surrounding states.

Attachment H – Operating Data

The following must be submitted:

1. Average daily rate or volume of fluid to be injected.

   The average anticipated injection rate will be approximately 1.25 to 1.5 million cubic feet of natural gas per day.

2. Maximum daily rate or volume of fluid to be injected.

   The maximum expected daily rate of natural gas injection is 1.75 million cubic feet per day.

3. Average injection pressure.

   The average expected injection pressure would be 1000 psig.

4. Maximum injection pressure.

   The maximum injection pressure would be 1,400 psig.

Include evidence to show that the injection pressure will not initiate new fractures or propagate existing fractures in the confining zone adjacent to USDWs.

As presented in Attachment C the proposed injection pressure maximum of 1400 psig will be significantly below the calculated pressure required to initiate fracturing in the Niagaran Guelph formation.

The following information must also be submitted:

1. Nature of the annulus fluid. This should include the type of fluid to be used in the annulus between the tubing and the casing and the corrosivity of the annulus fluid. Submit a report on the chemical name and amount of corrosion inhibitor added.

   At this point the Lanphar 1-12 is a proposed injection well but the company intends to use a corrosion inhibitor "WWT 1902 Packer Fluid Additive" which is a water soluble corrosion inhibitor bactericide and oxygen scavenger designed for use as a packer fluid additive and as a corrosion inhibitor by preferentially adsorbing a thin molecular film on all metal surfaces, thereby stifling the corrosion process.

2. Source and analysis of the physical and chemical characteristics of the injection fluid. The source of the injection fluid must be specific and include well numbers and locations. Test methods and procedures shall be specified and the analysis should include:

   a. Total dissolved solids, pH and specific gravity.
   b. A list of any inhibitors used to prevent scaling, corrosion or bacterial growth.

   The proposed injection well Lanphar 1-2 will not be used for injecting fluids but natural gas that is produced from the Niagaran Guelph formation in the Addison 12 field. A gas sample analysis is included in Appendix E.

Attachment I – Formation Testing Program

The permit application must propose to obtain the following information:

1. Formation Fluid pressure must be determined by measuring the static fluid level in the well, drill stem testing, pressure transducer or other appropriate method.

   Bottom-hole formation pressures were obtained for Lanphar 1-12 after drilling and completion and are in presented in Appendix F. A bottom-hole pressure of 1557 psig was recorded.

2. Formation pressure may be based on historical fracturing data in the same field and formation or may be obtained from actual field data. The formation fracture pressure must be documented.

   The Niagaran Guelph formation in Lanphar 1-12 was not fracture stimulated and stimulation was limited to an acid treatment to clean up perforations and near well-bore cement damage.

3. Physical and chemical characteristics of the injection zone must include methods to obtain data on the formation water quality and in some cases, porosity and permeability:

   a. Formation water quality of the injection zone must be analyzed.

The Addison 12 field has produced minor to no amounts of formation water and no analyses have been conducted to date. All water that has been produced was kill fluid used in the completion operations.

b. Porosity and permeability – If there are wells in the AOR which penetrate the injection zone for which there are no records or are improperly plugged or abandoned.

   There are no wells in the AOR that have no records or were improperly plugged or abandoned.

   A core was obtained for most of the Niagaran Guelph formation (Brown) interval in the Lanphar 1-12 and the analysis is included as Appendix C.

Attachment J – Stimulation Program

This attachment is required for all wells. If no stimulation is proposed please state so.

No stimulation is proposed for Lanphar 1-12 .

Attachment K – Injection Procedures

For manifold monitoring systems only, submit a lease map and flow diagram showing the piping system layout, valve locations, monitoring point locations and a narrative explanation of the operation of the system.

The Addison 12 is not a manifold injection system.

Attachment L – Construction Procedures

For Class II wells not yet drilled a step by step schedule of the construction program must be submitted.

Lanphar 1-12 has been drilled and completed.

Attachment M – Construction Details

This attachment is required for all Class II wells. A schematic drawing of the surface and subsurface construction details of the well must be provided. The drawing must include:

1. The size, type, weight, grade and depth for the surface casing, long string casing and other casing or liner.
2. The size, type, weight, grade and depth of the tubing string.
3. Sketches and descriptions of the wellhead and packer.
4. Kelly bushing and/or ground surface elevations.
5. Total depth, injection interval and hole diameter of the well.
6. Number, type and location of centralizers and/or cement baskets if used.
7. Class type, slurry weight, slurry volume, location and quantities of cement. This information should be documented.
8. External pressure (collapse resistance). Internal yield pressure and axial loadings (joint strength) for both the casing and tubing.

Schematic diagrams of the surface and subsurface construction details are attached in Appendix G.

Attachment N – Changes in Injection Fluid

This application requirement does not apply to Class II wells.

Attachment O – Plans for Well Failures

Permit applications must submit a proposed contingency plan outlining methods to prevent the migration of fluids into any USDW in the event of a well failure. The plan should list types of well failures with the proposed methods of shutdown for each type of well failure. The plan should also include an alternative method to dispose of produced brine.

Contingency Plan

Having reviewed the records for Lanphar 1-12, Lanphar 7-12 and Lanphar 2-12 (Appendix A) the wells would appear to have been adequately sealed which would prevent the updip migration of injection substances, which is in this case sour natural gas. In all offsetting wells the 11 ¾" surface casing was cemented to surface and Lanphar 2-12 and Lanphar 7-12 there are 8 5/8" and 5 ½" casing cemented in-place. Both the Lanphar 1-12 and Lanphar 7-12 were perforated in the Niagaran Guelph formation (injection interval). Lanphar 2-12 was not perforated in the Niagaran Guelph or other formations and the Niagaran Guelph interval was cemented-off behind the 5 ½" casing.

Potential Well Failures and Proposed Methods of Shutdown:

1. A Natural Gas Leak at the Wellhead

   If it is a small leak the wellhead will be equipped with H2S sensors which will shut-down the compressor with H2S values of 5 ppm or greater and prevent continued injection of natural gas to the injection well. The wellhead is equipped with a check valve which prevents the outflow of injected natural gas. If it is a significant leak the low-pressure monitor on the compressor will automatically shutdown injection to the injection well. The system would be vented to the flare and the leak repaired. With the Lanpar 1-12 injection well shut-in the option would be to continue utilizing the existing gas injection well; Lanphar 3-12 or partially shutdown production at the facility.

2. Pipeline Disruption

   The compressor is equipped with an automatic shutdown system for low pressure or high pressure. A disruption would cause the low pressure monitor to automatically shut-down the compressor. The remaining pipeline pressure and natural gas would be bled down and directed to the facility flare. The system would be shut-down until the pipeline disruption is repaired and tested.

3. Freezing-off at the Wellhead and/or in the Subsurface

   Freeze-offs do occur occasionally due to hydrate buildup/restriction at the wellhead or in the subsurface. The automatic high/low pressure monitor at the compressor is set for a discharge maximum pressure of 1,400 psig. This pressure is significantly below the fracture pressure of the formation and below the maximum operating pressure of the pipeline. On high discharge pressure the compressor automatically shuts down. The pressure and natural gas in the pipeline is bled down and directed to the facility flare. A methanol high-pressure injection pump is attached to the wellhead and methanol is injected into the wellhead and down the tubing until the restriction is relieved.

4. Injection Well Will Not Accept Injected Natural Gas.

   If the injection well no longer accepts the injection of natural gas, the high-pressure monitor on the compressor automatically shuts down the injection of natural gas to the injection well. If methanol injection (discussed above) does not relieve the lack of injectivity, additional methods will be employed to restore injectivity. The additional methods would include injection of hot fresh water (to alleviate salt and/or paraffin plugging) and injection of acid (to address plugging by clay or carbonate fines).

Alarm System

An alarm system is present at the compressor that signals that the injection system has reached the maximum allowable injection pressure of 1,400 psig. The compressor and facility is automatically shut-down at 1,400 psig. and an alert is sent to the facility operator.

Steps to Prevent Migration

1. Injection pressures will be limited to a maximum of 1,400 psig, which is significantly below the calculated injection pressure to induce fracturing for the Niagaran Guelph at the proposed injection depths (Attachment C).

   Injection pressures will be monitored on a daily basis and there will be high/low pressure monitors at the Lanphar 1-12 wellhead and at the compressor. The compressor will be set to shutdown if pressures exceed or are below the set values.

2. The injection zone in Lanphar 1-12 will be isolated from the 5 ½" casing by means of a packer and the natural gas will be injected though 2 7/8" tubing set on the packer. Corrosion inhibitor will fill the annulus between the 5 ½" casing and 2 7/8" tubing.

3. A mechanical integrity test (MIT) shall be conducted on the injection well prior to use and at least once every five years.

Attachment P – Monitoring Program

A monitoring program must be submitted which details the monitoring devices to be used to measure pressures and volumes. The annulus should be monitored with a gauge designed to indicate both a vacuum and positive pressure. The operator will be required to monitor injection pressure, annulus pressure, flow rate and cumulative volume of the injected fluid.

Lanphar 1-12 will be monitored both at the wellhead and at the facility (compressor). Gauges will be installed at the wellhead to monitor both vacuum and positive pressure on the annulus and injection pressure on the 2 7/8" tubing. The flow rate and cumulative volumes of injected natural gas will be monitored with a natural gas chart recorder and compiled on a daily basis.

Attachment Q – Plugging and Abandonment Plan

All Class II wells must submit a plan for plugging and abandonment. The plan must describe how the wells will be plugged with cement in a manner which will not allow the movement of fluids either into or between USDWs.

The plan must include detailed descriptions of the following information:

1. Method to place the well in static equilibrium. A well must be abandoned in a state of static equilibrium with the mud weight equalized top to bottom by circulating the mud in the well at least once prior to the placement of the cement plugs.
2. The type, number and method of placement (including elevation of the top and bottom) of plugs to be used. Include tagging of plugs unless a bridge plug is used.
3. The type, grade and quantity of cement to be used.
4. The cost of plugging and abandoning the well.

A plugging and abandonment plan for Lanphar 1-12 is attached as Appendix H. An independent third-party plugging cost estimate is attached in Appendix H.

Attachment R – Necessary Resources

Class II applicants must demonstrate and maintain financial responsibility and resources to close, plug and abandon the underground injection operation of permitted wells. The applicants must submit acceptable financial coverage for the wells to EPA.

Energex Petroleum (USA) LLC currently has a $250,000 bond posted with the State of Michigan Department of Environmental Quality. The state blanket bond (Appendix I) covers 10 wells which are compiled in Schedule A (Appendix I). Review of the plugging commitments of the existing 10 wells on the $250,000 blanket bond; of which one well Lanphar 3-12 is an EPA and DEQ approved injection well (MI-125-2D-0004) and Lanphar 1-12; which is the subject well of this EPA application for injection (MI-125-2R-0003) and the EPA prescribed formula of 75% of the estimated actual cost to plug and abandon the wells listed under the bond; a shortfall of approximately $85,000 exists in bonding requirements. According to this review Energex would be required to post an additional bond to cover this shortfall.

Attachment S – Aquifer Exemptions

Class II wells may not inject into a USDW. An aquifer exemption may be applied for in certain circumstances.

Energex does not plan to inject into a USDW.

Attachment T – Existing Permits

Provide a complete listing of permits or construction approvals for any facility owned and/or operated by the applicant in the areas covered by the application. If no permits or construction approvals are held state so.

Energex Petroleum (USA) LLC has an injection permit for Lanphar 3-12, which is also located in the Addison 12 unitized pool. The EPA injection control permit is #MI-125-2D-0004

Attachment U – Nature of Business

Briefly state the nature of the business, such as an oil production company or a brine disposal company.

Energex Petroleum (USA) LLC is an oil production company.

Mechanical Integrity Testing (MIT)

The demonstration of mechanical integrity is a two part test. The first part must demonstrate there is no significant leak in the casing, tubing or packer. Generally, one of the following methods must be used to evaluate the absence of significant leaks:

1. Continuous monitoring of a positive annulus pressure provided that an initial pressure test has been run; or
2. Pressure test of the annulus once every five years.

The second part of the MIT must demonstrate the absence of significant fluid movement into an USDW through vertical channels adjacent to the injection well bore. One of the following methods must be used:

1. A temperature log, provided that a baseline temperature log was run when the well was completed; or
2. A noise log; or
3. Cementing records demonstrating adequate cement to prevent significant fluid movement. This may require a cement evaluation log.

A cement bond log was obtained for Lanphar 1-12 and is included in Appendix J and indicates good cement bond above the upper perforated interval at 4156' KB in the injection zone to 3380'KB (a total of 776 feet).

LIST OF FIGURES, TABLES AND APPENDICES

FIGURES

TABLES

APPENDICES

APPENDIX G

APPENDIX H

OMB No. 2040-0042 Approval Expires 11/30/2014

EPA

United States Environmental Protection Agency
Washington, DC 20460

PLUGGING AND ABANDONMENT PLAN

Name and Address of Facility	Name and Address of Owner/Operator
Addison 12 Facility, 1857 East Leonard Rd, Addison Twp., Michigan USA, 48367	Energex Petroleum (USA) LLC., 2105 Victoria Ave., Windsor, Ontario, Canada, N8X 1P8

Locate Well and Outline Unit on Section Plat - 640 Acres

N

W E

S

State	County	Permit Number
Michigan	Oakland	32168

Surface Location Description

____ 1/4 of nw 1/4 of sw 1/4 of se 1/4 of Section 12 Township 5N Range 11E

Locate well in two directions from nearest lines of quarter section and drilling unit

Surface
Location ____ ft. frm (N/S) S Line of quarter section
and ____ ft. from (E/W) W Line of quarter section.

TYPE OF AUTHORIZATION

- [x] Individual Permit
- [ ] Area Permit
- [ ] Rule

Number of Wells 1

Lease Name Lanphar

WELL ACTIVITY

- [ ] CLASS I
- [x] CLASS II
  - [ ] Brine Disposal
  - [x] Enhanced Recovery
  - [ ] Hydrocarbon Storage
- [ ] CLASS III

Well Number #1-12

CASING AND TUBING RECORD AFTER PLUGGING

SIZE	WT (LB/FT)	TO BE PUT IN WELL (FT)	TO BE LEFT IN WELL (FT)	HOLE SIZE
5.5	15.5		959	7.875
8.625	24		990	10.625
11.75	Unknown		563	15

METHOD OF EMPLACEMENT OF CEMENT PLUGS

- [x] The Balance Method
- [ ] The Dump Bailer Method
- [ ] The Two-Plug Method
- [ ] Other

CEMENTING TO PLUG AND ABANDON DATA:	PLUG #1	PLUG #2	PLUG #3	PLUG #4	PLUG #5	PLUG #6	PLUG #7
Size of Hole or Pipe in which Plug Will Be Placed (inche	5.5	5.5	5.5/7.87	7.87/8.6	8.625/11	11/11.75	
Depth to Bottom of Tubing or Drill Pipe (ft	4305	4146	3430	2632	1592	667	
Sacks of Cement To Be Used (each plug)	50	32	60	75	100	404	
Slurry Volume To Be Pumped (cu. ft.)	53.42	34.2	64.1	80.1	106.9	432.5	
Calculated Top of Plug (ft.)	4146	3896	3210	2402	1400	Surface	
Measured Top of Plug (if tagged ft.)							
Slurry Wt. (Lb./Gal.)	15.8	15.8	15.8	15.8	15.8	15.8	
Type Cement or Other Material (Class III)	Class A	Class A	Class A	Class A	Class A	Class A	

LIST ALL OPEN HOLE AND/OR PERFORATED INTERVALS AND INTERVALS WHERE CASING WILL BE VARIED (if any)

From	To	From	To
4156	4180		
4190	4206 (Cement squeezed-off)		
4230	4250		
4268	4278		

Estimated Cost to Plug Wells

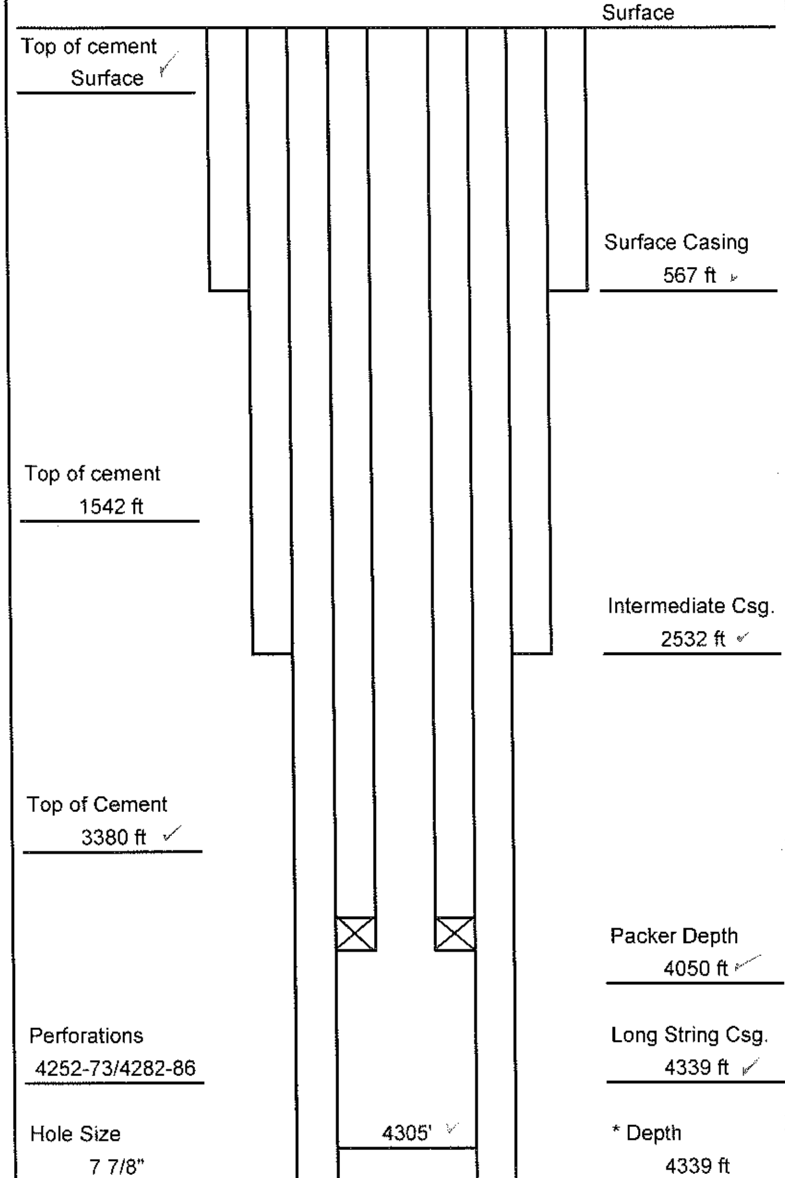
$72,300

Certification

I certify under the penalty of law that I have personally examined and am familiar with the information submitted in this document and all attachments and that, based on my inquiry of those individuals immediately responsible for obtaining the information, I believe that the information is true, accurate, and complete. I am aware that there are significant penalties for submitting false information, including the possibility of fine and imprisonment. (Ref. 40 CFR 144.32)

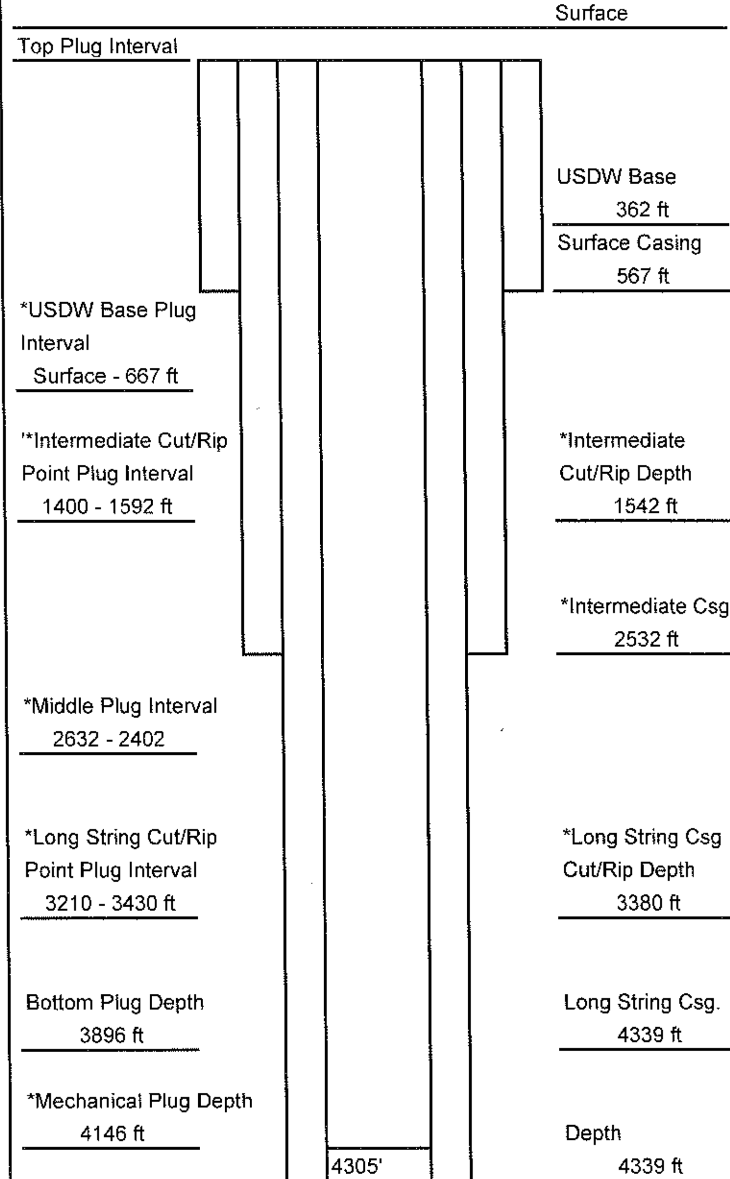
Name and Official Title *(Please type or print)*	Signature	Date Signed
Duncan Hamilton, Chief Operating Officer		11/20/2015

ORIGINAL WELL CONSTRUCTION DURING OPERATION	PLUGGING AND ABANDONMENT CONSTRUCTION
Lanhpar 1-12	Lanphar 1-12



** Add Any Additional Information

* May not Apply Plugged-back Total Depth = 4305'



** Add Any Additional Information

* May not Apply

LIST OF ALL OPEN AND/OR PERFORATED INTERVALS AND INTERVALS WHERE CASING WILL BE VARIED

Specify Open Hole/ Perforations/ Varied Casing	From	To	Formation Name
Perforations	4156	4180	Niagaran (BRN)
Perforations (cement squeezed-off)	4190	4206	Niagaran (BRN)
Perforations	4230	4250	Niagaran (BRN)
Perforations	4268	4278	Niagaran (BRN)

Methner Consulting

Office Phone 989-465-0091

P.O. Box 1071

Cell Phone 989-621-8220

Mt. Pleasant, Mi 48804

Prepared
11/13/2015

Abandonment Program
Lamphar # 1-12
Addison Township , Oakland County
Permit # 32168

Well Information
Casing Information
11 3/4 set @ 567' and cemented with 550 sacks (cemented to surface)
8 5/8 set @ 2532' and cemented with 200 sacks . Cement top 1542' calculated
5 1/2 set @ 4339' and cemented with 150 sacks . Cement top 3380(bond log)
2 7/8 tubing set on Baker Lok-set packer @ 4050'

Perforations :
4156-4180
4190-4206(squeezed off w/ cement)
4230-4250
4268-4278
Total Depth 4339

Plugged Back Total Depth 4305'

Elevations:
KB 1054'
GL 1041'
KB- GL 13'

Work Plan

1. Move in and set up service rig . Verify all crew members have been H2S certified. Personal H2S monitors will be worn by all personell on site. Full safety trailer will be on site until job is completed.Gas emissions are to be kept to a minimum with kill fluid.

2. Safety meeting to be held each day prior to start of operations. Well will be killed and controled with brine.

Contd

3. Remove Tubing head and install H2S trim BOP with blind rams as well as 2 7/8 rams.Function test BOP. Pressure test BOP at low(250psi) and high pressure(1500psi) for 15 mins each.

4. Unset Baker packer. Trip out of hole with packer & tubing.There is 134 joints of 2 7/8 tubing with shaved collars. A Baker sour service SS 2.31 profile nipple is above packer.

5. Remove packer and pick up 5 1/2 cement retainer & trip in hole to 4146'. Set cement retainer sting out & sting back in to retainer.Maintain well control at all times by pumping brine at a slow rate down annulus.

6. Hold safety meeting with cementing company and crew prior to rigging up cementers.

7. Sting back in to retainer and establish injection rate .

8. Mix and pump 50 sx Class A cement thru retainer.& sting out of retainer.Mix and pump 32 sacks cement on top of retainer.

9. Trip out of hole with tubing and close blind rams for overnight.

10. Wait on cement overnight.

11. Trip in with tubing to top of cement(should be 250' above retainer)

12. Pressure test wellbore to 500 psi & hole for 15 minutes to verify plug and casing integrity.

13. Trip out of hole .

14. Spear 5 1/2 casing and remove slip and seal assembly.

Contd

15. Install 5 1/2 casing rams in BOP.

16. Rig up Wireline truck to free point and shoot 5 1/2 casing.Frepoint and shoot casing off.

17. Pull casing out of hole checking for NORM as it is pulled.

18. Remove BOP and install 11" X 3000 BOP with pipe and blind rams.

19. Pick up 8 5/8 casing spear and 2 7/8 drill pipe sub and remove slip and seal assembly.

20. Rig up wireline company and free point and shoot 8 5/8 casing.

21. Rig down wireline truck & trip out with 8 5/8 casing checking for NORM as it is pulled.

22.Install 2 7/8 and blind rams in BOP.

23. Trip in hole with tubing to 50' below 5 1/2 casing stub and spot 60 sacks Class A- Pull tubing to 2632' check for static hole. If static mix and pump 75 sacks of Class A.Pull tubing to 1592(50' below 8 5/8 stub) and check for static hole.Pump 100 Sacks at 1592'

24. Pull tubing to 667'(100' below 11 3/4 surface casing.)

25. Mix and pump 404 sacks of Class A cement & trip out of hole

26. Wait on cement for 4 hours and monitor fluid level- if static proceed.Tag cement must be within 30' of surface.

27 Rig down service rig.

28. Cut and cap all casings 4' below ground level and weld 1/2" plate wit permit # 32168 on plate.

29. File plugging form with DEQ within 60 days of completion. Copies of service companiies records to be included with filing report.

Byron K Methner
Methner Consulting
Byron K Methner

Office 989-465-0091
Cellular 989-621-8220

Met' · Consulting
P.O.Box 1071
Mt Pleasant, Mi 48804

111/12/2015

Service and Equiptment Cost

Service Rig & Per Diem		$21,360.00
Wireline Services		$9,960.00
Cementing Service		$20,995.00
Packer Service		$2,500.00
Norm Detection		$500.00
Equiptment Rentals		$11,850.00
Supervision		$6,000.00
Water delivery		$4,250.00
H2S Safety Trailer	inc delivery & return	$3,860.00
		$81,275.00
	5% Contingency	$4,064.00
	Total Estimated Cost	$85,339.00

APPENDIX I

Company

BONDS

Last Modified 02/03/2014

Bonds | Display Half Bonds

Bond No. 385111494824

Purpose Oil Well Blanket Bond, Pt

Status Active

Typ Instrumnt Certificate of Deposit

Amount $250,000

Maximum Number of Wells

Total Number of Permits 10

Guarantor COMERICA BANK 5676

IssueAgt

Phone (800) 537-5337 **Ext**

Permittee ENERGEX PETROLEUM INC 6519

Bond Amounts

	Up to 2000'	2000 - 4000'	4000 - 7500'	>7500'
Single:	$10,000	$20,000	$25,000	$30,000
Blanket:	$100,000 Max# 100	$200,000 Max# 100	$250,000	$250,000

Dates

Start 01/23/2014

Released

Cancel

Limited

Wells Covered by Bond

Permit N	API Well No.	Well Name	Permittee
29994	21-099-29994-00-00	JONES UNIT 1-30	ENERGEX PETROLEUM INC
30518	21-099-30518-00-00	ROSS, LORNE UNIT 1-31	ENERGEX PETROLEUM INC
32168	21-125-32168-00-00	LANPHAR, MELVIN F 1-12	ENERGEX PETROLEUM INC

Record: 1 of 10 No Filter Search

Notes

frmBondWells_MI

Permit No	API Well No.	Well Name	Permittee	DTD	TVD	Status
29994	21-099-29994-00-00	JONES UNIT 1-30	ENERGEX PETROLEUM INC	4030		SI
30518	21-099-30518-00-00	ROSS, LORNE UNIT 1-31	ENERGEX PETROLEUM INC	3902		SI
32168	21-125-32168-00-00	LANPHAR, MELVIN F 1-12	ENERGEX PETROLEUM INC	4337		SI
32366	21-125-32366-00-00	LANPHAR, MELVIN F 2-12	ENERGEX PETROLEUM INC	4425		DC
32541	21-125-32541-00-00	LANPHAR, MELVIN F 3-12	ENERGEX PETROLEUM INC	4368		SI
32579	21-125-32579-00-00	MORRIS, DEWEY JR ET AL 4-12	ENERGEX PETROLEUM INC	4316		SI
39257	21-125-39257-00-00	LANPHAR 7-12	ENERGEX PETROLEUM INC	4390		SI
24615	21-147-24615-00-00	MARCINKIEWICZ, EUGENE J 2	ENERGEX PETROLEUM INC	2913		SI
24616	21-147-24616-00-00	STOLTZ, J GRANT 2	ENERGEX PETROLEUM INC	2913		SI
42634	21-147-42634-00-00	DEWALD 2-18	ENERGEX PETROLEUM INC	2950		PR

Joe Pettit
Compliance & Bonding Specialist, Office of Oil, Gas, and Minerals
P.O. Box 30256
Lansing, MI 48909-7756
pettitj@michigan.gov
Telephone: 517-284-6837
Fax: 517-241-1595

Schedule A

Energex Wells on Michigan State $250,000 Blanket Bond

Well Name	Permit #	Total Depth (FT)	UIC Approval	Estimated Plugging Cost	Estimated Plugging Cost @ 75%	Michigan State Bond Allotment	Michigan State Bond Deficit To UIC
Jones Unit 1-30	29994	4,030		$35,000	$26,250	$25,000	
Ross Lorne Unit 1-31	30518	3,902		$35,000	$26,250	$20,000	
Lanphar 1-12	32168	4,337	Applied	($85,000)*[1]		$25,000	$85,000
Lanphar 2-12	32366	4,425		$20,000*[2]	$15,000	$25,000	
Lanphar 3-12	32541	4,368	Yes	($72,000)*[1]		$25,000	$NIL
Morris 4-12	32579	4,316		$35,000	$26,250	$25,000	
Lanphar 7-12	39257	4,390		$35,000	$26,250	$25,000	
E. Marcinkiewicz 2	24615	2,913		$25,000	$18,750	$20,000	
Grant Stoltz 2	24616	2,913		$25,000	$18,750	$20,000	
Dewald 2-18	42634	2,950		$25,000	$18,750	$20,000	
Total					**$176,250**	**$230,000**	**$85,000**

***[1] Rounded to nearest $1,000**

***[2] Well is cased to TD and never completed as a producing well**

Stephen M. Jann, Chief
Underground Injection Control Branch
U.S. Environmental Protection Agency
77 West Jackson Boulevard, WU-16J
Chicago, Illinois 60604-3590

Dear Mr. Jann:

This letter requests that the attached State Bond # **385111494824** in the amount of $250,000 be considered an acceptable mechanism for meeting the Federal Underground Injection Control program financial responsibility requirement for the following well:

1. Well Name: **Lanphar 1-12**

2. Well Location: Township: **5N** Range: **11E**

   Section: **12** 1/4 Section: **SE**

   County: **Oakland**

3. UIC Application #: **MI-125-2R-0003**

4. Owner/Operator Name: **Energex Petroleum (USA) LLC**

5. Address: **2105 Victoria Ave.**
   Windsor, Ontario
   Canada, N8X 1P8

6. Phone: **(519) 252-1800**

I certify under the penalty of law that I have personally examined and am familiar with the information submitted in this document and that, based on my inquiry of those individuals immediately responsible for obtaining the information, I believe that the information is true, accurate and complete. I am aware that there are significant penalties for submitting false information, including the possibility of fine and imprisonment. (Ref. 40 CFR 144.32)

Duncan Hamilton, C.O.O		November 16, 2015
Name and Official Title	Signature	Date Signed